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Large Capacity, Multi-Fuel, and High Temperature Working Fluid Heaters to Optimize CSP Plant Cost, Complexity and Annual Generation

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Abstract. This paper analyses the potential to optimize high temperature fluid back-up systems for concentrating solar power (CSP) plants by investigating the cost impact of component capacity and the impact of using multiple fuels on annual generation. Until now back-up heaters have been limited to $20MW_{th}$ capacity but larger units have been realised in other industries. Installing larger units yields economy-of-scale benefits through improved manufacturing, optimised transport, and minimized on-site installation work. Halving the number of back-up boilers can yield cost reduction of 23% while minimizing plant complexity and on-site construction risk. However, to achieve these benefits it is important to adapt the back-up heaters to the plant's requirements (load change, capacity, minimum load, etc.) and design for manufacture, transport and assembly.

Despite the fact that biomass availability is decreasing with increasing direct normal irradiance (DNI), some biomass is available in areas suitable for CSP plants. The use of these biomass resources is beneficial to maximise annual renewable energy generation, substitute natural gas, and use locally/seasonally available biomass resources that may not be used otherwise. Even small biomass quantities of only 50,000 t/a can increase the capacity factor of a $50MW_e$ parabolic trough plant with 7h thermal energy storage from 40 to 49%. This is a valuable increase and such a concept is suitable for new plants and retrofit applications. However, similar to the capacity optimisation of back-up heaters, various design criteria have to be considered to ensure a successful project.

INTRODUCTION

Most CSP plants have natural gas fired high temperature fluid (HTF) heaters to start the plant and keep it operating during DNI fluctuations or, depending on operational philosophy, at night. These HTF heaters have small capacities of up to $20MW_{th}$ which is not ideal for larger CSP installations, such as $50MW_e$ Andasol or $100MW_e$ SHAMS One, as they need multiple units. The SHAMS One plant for example has 7 HTF heaters [1], which not only increase the specific unit cost but also plant complexity. Reducing the unit number to 2-3 would still ensure redundancy but reduce investment and system complexity. To ensure operational flexibility the heaters can be designed for low part-load operation, e.g. 20%.

Also these heaters are always natural gas fired and the use of multi-fuel units is interesting as such units could not only lower natural gas consumption but also increase the plant's annual renewable energy generation and maximize the use of locally available fuels.

Currently, parabolic trough systems are the predominant CSP technology and despite significant increases in solar tower and Fresnel capacity, the technology is expected to deploy many more plants and retain the largest

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generation capacity for many years. Therefore it is essential to identify new cost saving opportunities, not only for parabolic trough but also tower and Fresnel systems, and larger HTF heater units are one piece of the puzzle.

Current HTF heaters heat thermal oils but with molten salt systems, including tower, trough and Fresnel, expected to be significantly more relevant in the future, heater systems have to be able to heat molten salts for start-up and back-up purposes. This poses some design challenges but expertise from the boiler design industry is available to address these issues.

DESIGN CONSIDERATIONS FOR LARGE THERMAL OIL HEATER

Current thermal oil heater in CSP plants have a capacity of up to $20MW_{th}$ which is not ideal for larger plants as it leads to the design, construction, installation, and maintenance of multiple units. Additionally, more piping is required for multiple units. In particular, maintenance should be considered as all safety equipment, valves etc. have to be checked regularly and are therefore expenses occurring over the plant's entire lifetime. Redundancy is important and having only a single large capacity thermal oil heater, such as $80MW_{th}$, is not recommended. However, for a total heater capacity of $80MW_{th}$ it is sufficient to install 2x $40MW_{th}$ units rather than 4x $20MW_{th}$ units.

When designing thermal oil heaters the following features should be considered carefully to ensure efficient, safe and reliable operation:

- Flash point and fire point - The flash point of the fluid is the temperature at which the fluid flashes when exposed to an ignition source while the fire point is the point at which the fluid generates sufficient vapour to support continued combustion. Typically, the fire point is about 5-35°C hotter than the flash point. The flash point and the fire point provide an indication of the fluid´s volatility or its ability to generate vapour under a set of conditions.
- Auto ignition temperature - The temperature at which a fluid ignites without any external source. Reaching this temperature has to be avoided during the operation of the thermal oil heater. The combustion system should ensure the thermal stability of the thermal oil system across the entire firing range.
- Oil velocity - The oil flowing in the heater must have sufficient velocity, normally 1.2 to 3m/s in order to avoid excessive film temperatures.
- Under normal operating conditions, the increase in heating medium temperature shall not exceed the allowable temperature difference.
- To avoid accidents caused by the loss of thermal oil or leaks in the tubes, flow detectors should be used to permanently control the oil flow through the heater.
- Fuel specifications – The fuel characteristics influence the dimensions of the combustion chamber as well as of the heating surfaces. The fouling factor considered in the design and the allowable flue gas velocity in the heater has to be chosen accordingly. For natural gas fired units a typical fouling factor is 0,98 and flue gas velocities range from 14-20m/s or even higher depending on the maximum allowable draft losses.
- Load change – it is important to ensure that the boiler can compensate variations in steam outputs from the CSP component quickly to maximize annual generation and avoid unnecessary stress to the steam turbine. Quick start-up steam generators capable of changing load from 0-100% in less than 5 minutes, 20% load change per minute, have been realized, such as $80MW_{th}$ boilers in Cottbus, Germany [2]. Thermal oil heaters can reach similar load changes but the requirements have to be known in the design phase. Ensuring sufficient parallel tubes and headers is one key criteria to guarantee stabile and adequate flow throughout the system.
- To meet space constraints it is possible to design the thermal oil heater as horizontal or vertical units. Vertical units require a smaller footprint but by building the unit taller the construction and installation costs increase slightly. Figure 1 shows two exemplary designs.

To maximize the heater efficiency and therewith minimize natural gas consumption it is possible to use combustion air preheating or even flue gas condensation. Combustion air preheating has been realised in natural gas fired heater systems leading to heater efficiencies of 98%, e.g. $58MW_{th}$ in Novi Sad, Serbia. This is significantly higher than state-of-the-art gas fired heater systems. Flue gas condensers are possible too and can further raise efficiency but such systems require corrosion resistant materials, which are significantly more expensive. Considering the limited use of thermal oil heaters in CSP plants, their economic viability is therefore unlikely.

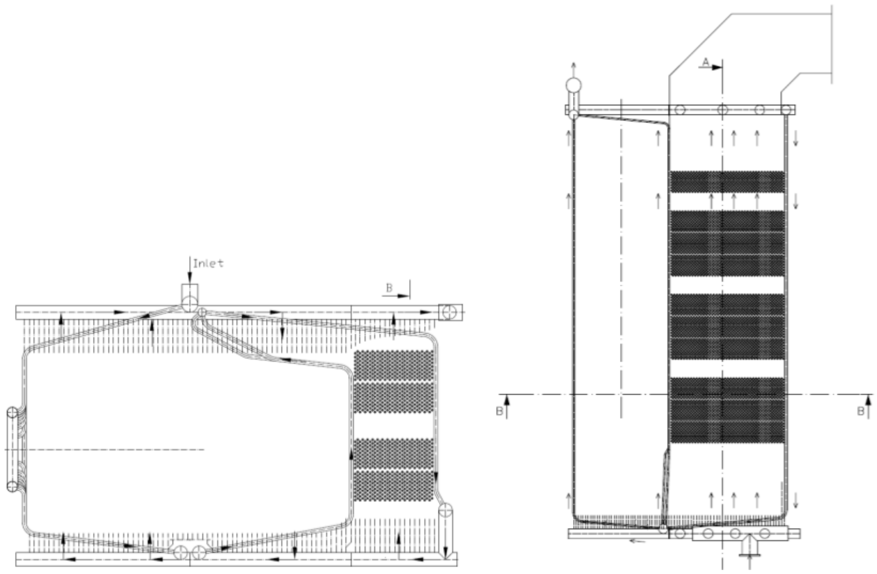

FIGURE 1. Horizontal (left) and vertical (right) thermal oil heater design options to meet space constraints.

DESIGN CONSIDERATIONS FOR MOLTEN SALT HEATER

Typically, a steam boiler directly connected to the steam turbine leads to better cycle efficiency. However, for operational reasons it makes sense to have a directly fired molten salt heater as such units enable the operator to preheat absorber tubes or the receiver in the morning and charge the thermal storage during the lower DNI winter period. The heater integration would be relatively simple by integrating the unit in between the hot and cold molten salt tanks.

The design considerations for molten salt heaters are similar to thermal oil systems, however a few key differences are to be considered, such as higher molten salt solidification temperature. The main features and concerns in the design of plants working with molten salt are:

- Achieve high efficiency - Current molten salts solidify at temperatures around 240°C and therefore the flue gas temperature downstream the last heating surface would be above 250°C, thus lowering boiler efficiency. To achieve a high boiler efficiency, the heater's flue gas exit temperature should be as low as possible and to lower the temperature after the last molten salt heating surface, the use of combustion air preheaters is recommended. See an example in Figure 2. Typically, combustion air temperature can be raised from ambient conditions to 280°C. However, the maximum temperature achievable depends on the fuel characteristics, combustion system, water content in the fuel, and molten salt solidification temperature.
- Filling and draining of the plant – In principle the filling and draining is similar to thermal oil units but the difference is the molten salt temperature being above 240°C. The higher temperature requires special valves, pumps, tanks, and procedures to ensure safe operation.
- Start-up and cool down procedure – The heaters need to be designed to cope with thermal expansion of the pressure parts. There is a lot of expertise available from thermal oil systems, which is partly transferable.
- Danger of freezing – salt solidification inside the tubes has to be avoided. Therefore the design needs to ensure a temperature profile across the boiler that keeps the molten salt temperature above 240°C at all load conditions required. Of particular concern is a blackout scenario where the temperature profile cannot be maintained. The draining time is therefore important in this regard.
- High thermal effort during anti-freeze operational mode – During heater standby the unit's temperature profile has to be maintained to avoid salt solidification. For limited periods, molten salt can be circulated through the heater from the storage tanks or the natural gas burner fired at standby capacity. However, both options are net energy losses. For longer shutdown periods it is recommended to drain the heater.
- Material requirements – Material selection is crucial but the molten salt compositions are well known as are the appropriate materials.

- Maintenance procedures – It is important to ensure that the unit/units can be drained completely for maintenance purposes. Various design options exist for thermal oil but the difference to molten salt is that the unit needs to be drained while the molten salt temperature is above 240°C. All heating surfaces need to be easily accessible to replace tubes if necessary.
- Stability of salt mixtures – Not only the lower but also the upper molten salt temperature is important to ensure longevity of the molten salts. Frequently exceeding the upper temperature limit leads to higher salt replacement rates and thus increased operational costs. Therefore the heater design, in particular the heating surfaces closest to the furnace, needs to ensure the appropriate temperature profile at all load conditions.

Various criteria have to be considered for molten salt heaters but there is a lot of expertise available from traditional boiler and heater designer/suppliers that can be used to minimize the risk of such units. It is recommended to use this expertise to not only lower technology risk but also shorten development times.

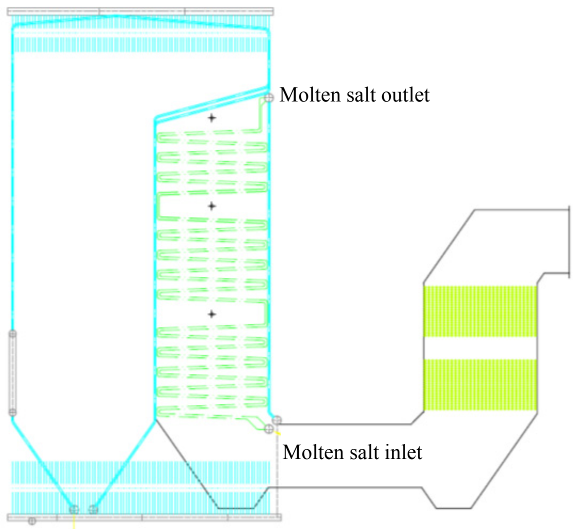

FIGURE 2. 60MWth molten salt heater example behind biomass furnace including heater walls (blue sections), convective heating surfaces (green sections), and combustion air preheater (yellow sections).

DESIGN CONSIDERATIONS FOR MULTI-FUEL HTF HEATER

At the moment all HTF heaters in CSP plants are natural gas fired, except the Borges CSP-biomass hybrid plant in Spain [3]. However, the use of multi-fuel HTF units is worth investigating as these could not only lower natural gas consumption, which is often limited to <15% annual generation, but also increase the plant's annual renewable energy generation and maximize the use of locally available fuels.

The design of HTF systems that can use multiple fuels has its own challenges in regards to heater efficiency, fouling, and part-loads. However, many units combining multiple fossil fuels, fossil and renewable fuels, and multiple renewable fuels have been built worldwide for different industries. Figure 3 shows a $28MW_{th}$ reference in Germany. This expertise can be transferred to CSP, which lowers technical and finance risk significantly.

The relevant design criteria for heater systems have already been addressed in this paper and therefore this section uses an actual reference plant to describe multi-fuel units. The peak capacity of the thermal oil heater shown in Figure 3 is $28MW_{th}$ with a temperature spread of 30K (255°C to 285°C) and a mass flow of about 1,100t/h.

The heater consists of a reciprocating grate system in a refractory lined combustion chamber and additional dust and natural gas burners. The fuel consists of woody waste materials, medium density fibre boards, saw dust from the medium density fibre board production, and natural gas. The grate uses the coarse wet parts from the fuel mixture while the burners use the fine dust. The fuel supply onto the grate occurs via screw feeders from the bunker. The bunker has safety equipment, such as cameras and temperature sensors, to prevent a bunker fire. The biomass materials are injected when the combustion chamber temperature has reached 600°C.

The boiler has six operational modes which can be chosen flexibly: a) saw dust firing only, b) natural gas and saw dust, c) natural gas only, d) solid biomass only, e) natural gas and solid biomass, and f) solid biomass and saw dust. The firing capacity reaches $28MW_{th}$ with all fuels. To control the inlet temperature of the exhaust gas from the combustion chamber a flue gas recirculation system is installed. An electronically controlled flap regulates the recirculation through the 5 m long channel.

The thermal oil heater is designed as single coil with 8 parallel tubes. Hence no collectors are necessary in order to distribute the thermal oil evenly. This construction simplifies the flow distribution significantly. The heater consists of a radiation and a convective section. The front, side and rear walls are realized as membrane walls. The convective and radiation areas are connected through a flue gas redirection above the joint ash hopper. All coils are designed to prevent overheating through the number of parallel tubes, tube arrangement, and flow control. The flue gas velocity in the heater does not exceed 9 m/s to avoid elevated erosion and corrosion rates from ash particles in the flue gas.

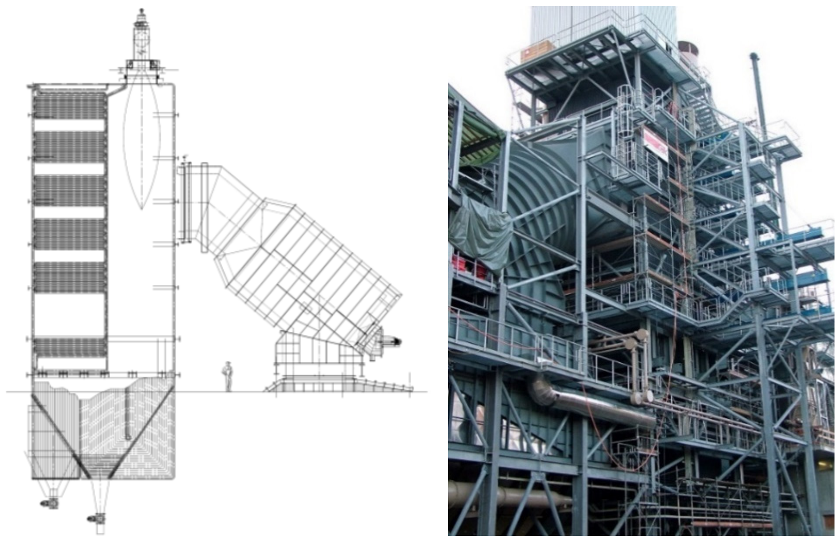

FIGURE 3. Example of a thermal oil heater with natural gas and biomass firing; Design (left) and during installation (right).

For CSP plants with limited thermal energy storage (TES), such as 3h, the integration of a biomass fired molten salt heater might be, despite some thermal inefficiencies caused by the secondary working fluid, a better option than a steam boiler. Such a plant configuration could shift electricity output through the energy storage system to higher electricity price periods, e.g. morning peak. Currently, there are no references for biomass fired molten salt heaters and therefore the technical risk would be slightly higher compared to a conventional steam boiler. On the other hand a biomass fired molten salt heater would have a lower cost than a steam boiler as the HTF pressure would be lower and the absence of a steam drum.

Typically, electricity prices are lower during the night than the day with peaks in the morning and evening. The evening peak could be covered with CSP charging the limited TES but the morning period could not be covered. However, with a molten salt biomass heater the plant could operate the steam turbine at minimum load at night and simultaneously charge the TES to dispatch maximum capacity as soon as electricity prices recover in the morning. A biomass fired HTF heater could also charge the TES during lower DNI winter days to ensure appropriate TES capacity to cover the high electricity price evening peak. Such an approach has been discussed in the past with the result that the daily revenue could increase by 6.1% [4].

LARGE CAPACITY THERMAL OIL HEATER CASE STUDY

The case study is based on a total thermal oil heater capacity of $80MW_{th}$ and compares 4x $20MW_{th}$ thermal oil heaters (scenario 1) with 2x $40MW_{th}$ units (scenario2). Two $40MW_{th}$ units are required to ensure redundancy.

Modelling

The modelling of this case study was carried out with Eckrohrkessel's in-house design software. The software is used in the daily design process, has been used to design more than 1,000 boilers and heaters, and is therefore considered reliable and accurate. The cost differences derive from actual project experience of the ERK Eckrohrkessel GmbH and its licensees. The costing is not provided as actual prices but percentage differences. The reason for that is that heater prices vary worldwide and by manufacturer due to labor cost, equipment, location etc.

Results and Discussion

Scenario 1 is based on the current maximum $20MW_{th}$ heater systems while scenario 2 applies with $40MW_{th}$ significantly larger heaters. With such a configuration it is possible to halve the number of heaters required from four to two units, which has positive technical and economic aspects. Table 1 summarizes the main results of the analysis.

The heater efficiency is unchanged as both systems can achieve the same flue gas outlet temperature. Relevant differences can be observed in the overall weight of the units with 40t for scenario 1 and 70t for scenario 2. Fewer units also reduce plant complexity in regards to piping, burners, valves, fans, draining, as well as electrical and mechanical equipment. This not only impacts capital expenditure but also operational expenditures as maintenance is required over the plants entire lifetime.

TABLE 1. Comparison of different heater options.

Scenario	Heater quantity	Capacity each unit, MW_{th}	Heater efficiency, %	Total weight of all heaters, t	Cost reduction, %
1	4	20	85	160	0
2	2	40	85	140	-23

Reducing the number of heaters has a positive capital cost impact as larger units offer significant economy-of-scale benefits. The overall cost reduction of scenario 2 compared to scenario 1 is 23%. The heaters itself and on-site installation have the largest cost reduction impact (27%) followed by foundations (19%), piping (17%), mechanical and electrical installation (10%), and pumping system (9%). The cost reduction derives from efficiency gains in the workshop, fewer components, and less on-site assembly work. If the site allows access of large units the thermal oil heaters could be transported to site fully assembled. Self-supporting thermal oil and water tube boilers have been transported in single units with capacities up to $100MW_{th}$. A $40MW_{th}$ thermal oil heater would have a length of 6,8 m, height of 4 m, and length of 13 m.

MULTI-FUEL HEATER CASE STUDY

A recent CSP-biomass hybrid analysis [5] identified various regions worldwide, which are theoretically suitable for CSP-biomass hybrid plants. Typically, biomass availability decreases with increasing DNI but in CSP suitable areas with DNI levels of 1,900-2,200kWh/m^2/year some biomass is still available, such as straw and other agricultural residues. The hybridization of CSP with biomass also enables CSP plants to move into lower DNI areas as demonstrated by the Borges plant in northern Spain [3].

The integration of multi-fuel heaters is relatively simple as natural gas fired HTF heaters are required anyway and adding the flue gas cleaning and limited fuel storage is possible when considering it in the planning stage. Due to the limited availability of biomass in high DNI areas it is unlikely that the biomass heater capacity would exceed $50MW_{th}$, unless the plant is in proximity to an agricultural processing plant, such as wheat, peanut or olive productions. Hence, it is possible to use smaller quantities of locally or seasonally available biomass, which might not be used otherwise as the infrastructure required would be too costly.

Modelling

As in in the thermal oil heater case study the modelling of this case study was carried out with Eckrohrkessel's in-house boiler and heater design software. The modelling is based on a 40 MW_{th} thermal oil fired heater using biomass and natural gas. The units can reach full capacity at biomass only, natural gas only, and a combination of both. In high DNI areas the types of biomass available varies, such as production or agricultural waste, and to avoid the focus on a single fuel this case study is based on a generic biomass feedstock with a calorific value of 10 GJ/t.

Results and Discussion

Using multi-fuel heaters with biomass and natural gas does not only have the benefit of substituting natural gas but increase annual plant generation/capacity factor. This leads to a higher usage of the capital intensive power block. Table 2 shows the impact of using biomass in a 50 MW_e parabolic trough plant with 7h TES. With only 50,000 t of biomass annually at a calorific value of 10 GJ/t it is possible to increase the plant's capacity factor from 40% to 49%. 50,000 t/a is not much and equals the annual fuel requirements of a 5 MW_e standalone biomass plant. In areas with 200,000 t of available biomass annually a capacity factor of 75% would be possible with only 7h TES. This equals the capacity factor of the Gemasolar tower plant in Spain which has 15h TES [6]. Therefore, a significant plant cost reduction is possible if biomass is available.

In addition to new CSP-biomass hybrid plants the retrofit of multi-fuel HTF heaters is promising as retrofits are lower cost due to the availability of existing infrastructure. When retrofitting a biomass fired heater to an existing CSP plant it is no possible to convert the existing natural gas fired units to biomass firing as these use finned tubes which would foul rapidly from biomass derived ash particles. Also the combustion chamber design is quite different for natural gas and solid fuel fired heaters. Hence, any biomass retrofit to a CSP plant would require a new biomass heater. It is very complicated to the cost for such a system in a generic form as pricing depends heavily on fuel type, existing CSP plant layout and configuration, local labor costs and plant location.

TABLE 2. Comparison of different heater options.

Biomass availability, t/a	Plant capacity factor, %	Annual generation, MWh
0	40	175,200
50,000	49	212,700
100,000	57	250,200
150,000	66	287,700
200,000	75	325,200

SOUTH AFRICAN CONSIDERATIONS

The South African energy market is competitive and equipment suppliers need to identify and exploit cost reduction opportunities. Cost optimisation possibilities for boiler and heater systems range from material selection and procurement, manufacturing, transport, to on-site installation. Exploiting these opportunities is important to ensure that local companies benefit from CSP installations in South Africa, high local content, and the growth of green jobs.

South Africa has qualified heater manufacturer and maintaining high quality under workshop conditions is not a problem when selecting the right suppliers. Transport and installation is more complicated as the infrastructure is limited in some areas of the country and on-site work has inherent quality and safety risks. Also on-site labor is more expensive than workshop staff. Both transport and installation cost can be minimised by modularizing back-up boilers/heaters as much as possible. To do this the design of the units is very important as the structure has to maintain its integrity during transport. The lowest cost options are single units and self-supported boiler have been transported to site with capacities of 120 MW_{th}. However, if the transport infrastructure is limited, the modules should be chosen as large as possible.

FIGURE 4. Manufacturing, transport, and installation of a 120 t/h, 400°C and 42 bar gas and oil fired water tube boiler in Cape Town, South Africa.

Figure 4 shows a natural gas and oil fired boiler in South Africa, which had to be transported to site in few modules. In the workshop the units were built to the maximum transport limits (weight, length, width, and height) and these few modules were transported to site. On-site little labor was required to complete the boiler and proceed to commissioning. Minimising on-site work is very important not only to minimise capital expenditure but also to increase safety. A recent accident at a CSP plant construction site in South Africa sadly supports this claim [7].

CONCLUSION

The paper/presentation demonstrates that optimised HTF heater systems (capacity and fuels) can lower CSP plant cost, increase availability, and make use of locally/seasonally available renewable energy sources, which may not be used otherwise. Reducing the number of back-up HTF heaters by increasing the individual unit capacity can lower the cost of these CSP plant components by up to 23%. Additionally, the use of larger units reduces plant complexity and maintenance costs.

The use of locally/seasonally available biomass materials in the back-up system of CSP plants can increase annual renewable energy generation and subsitute natural gas. Even small biomass quantities, such as agricultural waste products, can be used to optimise annual plant performance, in particular during the lower DNI winter period. These benefits can lower the levelised cost of electricity of CSP plants and help improve its competitiveness against other energy sources.

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